The Cost of Credit:

A Review of Credit Requirements in Western Energy Procurement

CONSULTANT REPORT

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ABSTRACT

Regulators, policymakers and developers are concerned that overly stringent credit requirements may restrict supplier competition and raise the price of power. Credit requirements are one tool available to utilities to prevent contract failure and to protect themselves financially in the event of default. Credit requirements include bid deposits, financial information, development security, and operating collateral. This report reviewed eighteen request for offers (RFOs) in order to quantify and compare credit requirements across both renewable and non-renewable solicitations. RFOs from California's Investor Owned Utilities (IOUs), Publicly Owned Utilities (POUs), and several western utilities were analyzed. The report finds that collateral amounts vary widely across utilities and are far from standard. California IOUs recent 2006 RFOs appear to be more similar in their credit requirements, and no longer use mark to market calculations of collateral. Collateral amounts based on nameplate capacity penalize low capacity factor projects, such as wind. The report cautions that the cost of obtaining collateral is more complex than simply the fee required by a lender for a letter of credit. It appears from the data that operating collateral adds roughly one dollar per megawatt-hour to the cost of power. Regulators should continue to monitor credit requirements to ensure that utilities are protecting themselves while not requiring excessive collateral.

KEYWORDS

Credit requirements, collateral, renewable energy, power purchase agreement, contract failure, wind power, mark to market, development security

CHAPTER 1: INTRODUCTION

This report was prepared for the June 27, 2006 workshop on credit policies held by the California Energy Commission (Energy Commission). The purpose of this report is to provide background information on credit policies as well as a methodology to compare credit requirements among California and other western utilities. Regulators, policymakers and developers are concerned that overly stringent credit requirements may restrict supplier competition and raise the price of power. This report provides an initial quantification and comparison of credit requirements across California's Investor Owned Utilities (IOUs), for both renewable and non-renewable procurements. The report also compares the credit requirements of California's IOUs to requirements imposed by the state's California Publicly Owned Utilities (POUs) and by a small number of other utilities in the western U.S.

Credit requirements are one tool available to utilities to prevent contract failure and to protect themselves financially in the event of default. A recent report on renewable energy contract failure,[1] prepared for the Energy Commission, showed that contract failure is a real issue for renewable generation projects, with the data showing that at least 30 percent of renewable contracts may be expected to fail based on experience to date. Utilities and others may believe that higher levels of development security will reduce contract failure rates. Though the contract failure report did not find a specific correlation between development security and contract failure rates, it would not be surprising if such a link did exist.[2] Clearly, the level and types of credit requirements must balance competing desires for robust supplier competition on the one hand and reduced risk of contract failure on the other. This report is focused on identifying and comparing credit requirements only. It does not intend to demonstrate the effects of credit requirements on contract failure rates, or how credit requirements may affect the competitiveness of solicitations.

The report is organized as follows:

- **Chapter 2** gives a summary overview of the types of credit requirements.
- **Chapter 3** discusses the methodology used in the report.
- **Chapter 4** reviews the requirements imposed in a variety of utility RFOs.
- **Chapter 5** provides some brief conclusions.

CHAPTER 2: AN OVERVIEW OF CREDIT REQUIREMENTS

Credit requirements are a complex, wide-ranging topic that encompasses many aspects of power purchasing. In short, credit requirements are a mechanism to protect parties in a power purchase contract from the possible default of the other party. Because default can take many forms, and can occur at different phases of the project development cycle, credit requirements come in many flavors and are enforced at different phases of the contract. Table 1 and Figure 1 list the major categories of credit requirements considered in this report, and indicate when in the contracting cycle they can come into effect.

Table 1. Categories of Credit Requirements

Requirement	When
Bid Deposits	During bid evaluation process, due either at bid submittal or short-list selection.
Financial Information	Used for bid evaluation, during project development and operation.
Development Security	From contract signing to commercial operation date (COD)
Collateral During Operation	From COD to contract termination

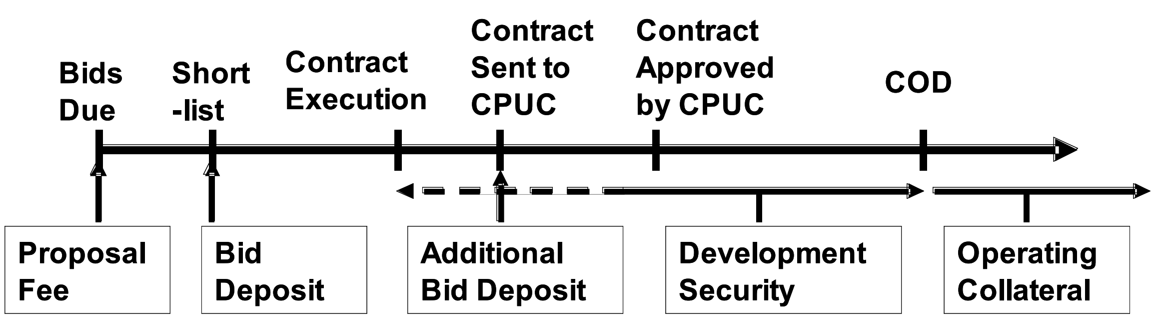

Figure 1. Timeline for Development and Security

While credit requirements can be imposed on both the seller and purchaser of power, this report focuses exclusively on the credit requirements demanded of power developers by utilities. Issues with utility creditworthiness and the credit requirements required of utilities are outside the scope of this report.[3] More specifically, this report focuses on the credit requirements for independent power projects (IPPs) that are built specifically to provide power to a utility. It touches only slightly on the credit requirements imposed on power marketers; entities that sell wholesale power to utilities.

Forms of Credit

Before discussing credit requirements, it is important to note the types of security that utilities accept. Cash, of course, is always accepted, but most developers would prefer not to tie up large amounts of equity as collateral, especially at the development or operational stage of the project.

The most common type of credit is the letter of credit, a cash guaranty from a lender for the required amount of security. Letters of credit are considered "liquid" security as they can be readily converted to cash. The developer pays a fee to the lender for the letter of credit, which typically range from 1-3 percent of the total amount of the letter of credit. These fees vary based on the perceived risk of the project, the credit quality of the developer, and other factors. For example if a project needed to obtain a $20 million letter of credit, the project would typically have to pay $200,000 to $600,000 each year to a lender for the letter of credit.

The "cost" to a project of a letter of credit, however, can be more than 1-3 percent of the letter of credit amount. First, smaller developers may be forced to place some amount of equity with the lender to secure the letter of credit, reducing the equity available for the project and increasing the returns necessary for the project. Secondly, the cost of a letter of credit reduces the cash available for financing, once again increasing the equity requirements for the project. Finally, a letter of credit reduces the overall borrowing capacity of the project.

An example may help clarify the impact of a letter of credit on the overall borrowing capacity of the project. A lender may have been willing to lend $200 million to a project and a utility may require a development security for the same project. Development securities are based on the capacity of the project, but generally do not exceed 5 percent of the project cost, in this example about $10 million. If the developer provides the development security to the utility through a letter of credit, the lender may actually lend less than $200 million because of the letter of credit. The borrowing capacity may be reduced by an amount equal to or less than the amount of the letter of credit, depending on the perceived risk of project default. Once again, less borrowing capacity translates to an increased demand for equity, which requires higher returns. These higher returns could make the project uneconomic.

Another form of collateral is guaranty from a creditworthy entity, usually the ultimate corporate parent of the project company. A guaranty ensures that the parent will be responsible for operating the project should the project company be unable to meet its obligations under the contract. The corporate parent must be a creditworthy company (normally with an unsecured bond rating of BBB+ or better) for a guaranty to be accepted. In most cases, however, developers structure projects specifically to avoid putting the parent company balance sheet at risk. This is normally done by setting up a limited liability company specifically for the project.

For operational collateral, there is often a “collateral threshold” which is based on the credit rating of the project company (or its parent). Higher credit ratings yield higher thresholds, allowing the developer to post less liquid collateral. These thresholds are revisited over the life of the contract, and if the credit rating of the developer or its guarantor is downgraded, the developer may be forced to put up more collateral.

Bid Deposits

Bid deposits are often required by utilities of developers when submitting a bid into a request for offers (RFO, also known as request for proposal or RFP). Bid deposits may be used to ensure that developers submit only serious bids and to cover the utility’s cost for reviewing the information in the bid. While bid deposits are not technically credit requirements, they are covered here because their purpose is somewhat similar to that of a credit requirement.

Bid deposits can be due at the time the bid is submitted (also known as proposal security), or when the developer’s bid is placed on the short-list. Utilities have different rules for when and if bid deposits will be refunded. Bid deposits can be specified as a flat fee, such as $2,000, but may also be specified as an amount based on the nameplate capacity or annual generation of the project. For example, a bid deposit could be set at $3 per kilowatt (kW) or $5 per megawatt-hour (MWh).

Bid deposits are a controversial topic. Many developers feel that bid deposits keep viable projects from bidding into RFOs, especially in the renewables market, where developers tend to be smaller. Conversely, larger developers may benefit from bid deposits that may eliminate smaller or less established bidders.

Financial Information

A crucial part of credit requirements is the financial information required of the developer. This information is required with the project proposal and it is typically required to be updated during the life of the contract. The financial information utilities require is broad and can encompass all aspects of the proposed project. Typical items requested of developers are listed below:

- Information on all entities involved with the project corporation, including the ultimate corporate parent.
- Historical (usually two or three years) of financial statements for the project company, its parent, and any joint venture partners. This includes Annual Reports and 10-K’s for public companies.
- A credit rating (if available) of the project company and its parent from Standard & Poors and Moody’s.
- A financing plan for the project, including debt/equity ratios, interest rates, loan term, and other key financial parameters.
- Pro forma budget for the project that includes both source and use of funds during development and construction.

This information helps the utility asses the ability of the developer to obtain financing and successfully build the project. Even though most project companies are structured as limited-liability companies, parental financial information is important as the parent will be the primary source of equity funds for the projects and has proven to be an indicator of the likelihood of project success. The project pro forma information helps the utility determine if the project is robust enough to be viable under a variety of possible future conditions. The utility also uses the pro forma to verify that the assumptions about debt rates, capital costs, and other critical factors are realistic.

Once a contract is awarded, financial information, especially the credit rating of the project company, remains crucial during the operations stage. The credit rating of the project company (if it has one) establishes a collateral threshold that affects the collateral needed during operation.

Development Security

Development security is the collateral required in the period between contract execution and the commercial operation of the energy facility. If the developer fails to build the project, or experiences delays in construction, any payments for damages specified in the contract will come from the development security. These are normally defined as “delay damages” for delays experienced in the construction schedule and “liquidated damages” in the case of project default. Development security helps the utility ensure that the developer meets the project schedule, which may include any construction milestones specified in the contract. The utility will seek a level of development security to make it “whole” if the developer fails to deliver, or delivers late, by compensating the utility for lost power and lost time. In addition to security for schedule, security is often required to ensure the contracted levels of capacity, heat rate, and emissions are developed as specified.

Development security, like bid deposits, is normally specified based on the nameplate capacity or annual generation of the facility. Development security is typically due on or within 30 to 60 days after contract award, and may be a condition for contract execution. Just as with bid deposits, smaller developers try to minimize these requirements as development security increases the cost of their projects.

Operating Collateral

Operating collateral comes into force after the commercial operation date (COD) of the project and is in force for the duration of the contract. Operating collateral is designed to protect the utility from a host of possible breaches of the counterparty:

- A failure by the project company to deliver the agreed energy, capacity, heat rate, or availability.
- The inability of the developer to operate and maintain the project (or deliver energy), due to financial difficulty or other factors (such as a failure to meet permitted emissions levels).

- An attempt by the project company to terminate the contract and sell to another party under more favorable conditions.

Operating collateral is designed to reduce the likelihood of contractual breach as well as to compensate the utility for substandard performance. Operating collateral is often set at a level that would allow the utility to purchase replacement power from the market while it contracts for another facility to be built, which can take several years. For this reason, operating collateral is sometimes set as a multiple of annual revenue, or as the difference between contract price and market price.

Typically, the amount of liquid operating collateral needed is based on a fixed amount or "mark-to-market" accounting, which is discussed below. Where fixed amounts are used, those amounts can vary greatly among utilities, and can be linked to the project's annual revenue, annual generation, or nameplate capacity.

Mark-to-Market

Mark-to-market accounting for collateral seeks to protect the utility from exposure, if the wholesale market price is above the contract price. Market prices above the contract price mean that if the project underperforms or is in default, the utility will have to purchase more expensive power on the market. Mark-to-market accounting attempts to quantify this exposure by aggregating the total amount future wholesale prices could be above the contract price. For example, if prices have a 95 percent chance of being $5/MWh above the contract price, then the utility's total exposure is $5/MWh times the annual generation times the number of years remaining on the contract. For a 20-year contract, this amount can reach large figures very quickly, so utilities normally only ask for some percentage of the total exposure to be covered with collateral. For short term (5-year) marketing contracts, utilities are more likely to ask for full collateral.

Calculating the amount of collateral required for mark-to-market accounting requires knowledge of future market price predictions, as well as sophisticated financial analysis tools. Most power marketers have the capability and tools to calculate mark-to-market collateral amounts, which is important as the amount of collateral required is recalculated on an annual, weekly, or even daily basis depending on the contract.

Mark-to-market accounting poses certain difficulties for renewable developers. Renewable developers generally do not have the expertise or tools to calculate the collateral amounts necessary. Periodic recalculation means the developer cannot know how much collateral will be required over the life of the contract up front. This makes it difficult to price the credit required into the price of power when bidding. In addition, there is no liquid or wholesale market in California for renewable energy, so it is unclear what price the utility should use when making mark-to-market calculations for renewable energy purchases.[4]

Non-liquid Options

For IPP-based generation projects, there are a number of ways utilities can help to protect themselves that do not require traditional credit instruments, such as a letter of credit or parental guarantees. One of the most common is exclusivity, or the demand that the project must sell the entirety of its output to the utility and to no other customer. Another protection for utilities is that most lenders require the developer to comply with its power purchase agreement (PPA).

Other forms of guarantees include subordinate liens (or mortgages) that ensure the utility has rights as a creditor second only to the lenders in the case of a bankruptcy or default. Utilities can also ask for “step-in rights” that allow the utility to take over ownership of the plant if the developer is unable to operate it for any reason. This can be a powerful tool for utilities if a project is viable, but the parent company is in financial trouble and is not operating the plant to specifications. On the other hand, if the project is under-performing, having rights to a distressed asset may not be helpful to the utility.

CHAPTER 3: METHODOLOGY

This report was prepared primarily by analyzing Request for Offers (RFOs) from California IOUs, California POUs, and RFOs from other western IOUs. While much information can be gleaned from RFOs and their accompanying "model" contracts, the drawback of this method is that credit requirements are not always explicitly spelled out in these documents. In addition, the "model" contracts may be significantly changed during contract negotiations between utilities and developers. Nonetheless, we restricted our analysis to publicly available utility RFOs and model contracts. The eighteen RFOs that were analyzed are listed in Table 2.

Table 2. RFOs Analyzed

Utility	RFO
California IOUs	
Pacific Gas & Electric (PG&E)	2005 and 2006 Renewable, 2005 All-Source
Southern California Edison (SCE)	2003, 2005 and 2006 Renewable, 2005 All-Source (5-year)
San Diego Gas & Electric (SDG&E)	2005 and 2006 Renewable, 2006 All-Source
California POUs	
Sacramento Municipal Utility District (SMUD)	2004 Renewable
Los Angeles Department of Water and Power (LADWP)	2004 Renewable
Southern California Public Power Authority (SCPPA)	2005 Renewable
Non-California	
Sierra Pacific/Nevada Power	2005 Renewable
PacifiCorp	2004 Renewable
Xcel Energy	2004 Renewable, 2004 All-Source
Arizona Public Service (APS)	2006 Base Load RFP

In addition to the utility RFOs listed in Table 2, we also reviewed RFOs from Bonneville Power Administration (BPA), Idaho Power, and Western Area Power Administration (WAPA). These RFOs either contained no credit requirement information (BPA and WAPA) or were not accompanied by model contracts (Idaho Power). These RFOs are therefore not included in the summary

In the analysis, two hypothetical renewable projects are used as "proxies" in order to compare the relative magnitude of credit requirements. The two projects are a 100 MW wind farm and a 40 MW geothermal project. Specific assumptions are listed in Table 3, and are based on reasonable 2006 California assumptions regarding price, size, and capacity factor. These projects were chosen because they have roughly equal annual generation (approximately 300,000 MWh) but have characteristics that may result in different bid deposits, development security, and operating collateral. These projects were also used as proxies for the all-source RFOs, to allow for a comparison across all types of RFOs.

Table 3. Proxy Project Assumptions

Assumption	**Geothermal Project**	**Wind Project**
Project Size	40 MW	100 MW
Capacity Factor	85%	35%
Expected Annual Generation	297,840 MWh	306,600 MWh
Contract Price	$70/MWh	$60/MWh
Expected Annual Revenue	$20,848,800	$18,396,000
Contract Term	20 years	20 years
Capital Cost ($/kW)	$3,000	$1,500
Total Capital Cost ($)	$120,000,000	$150,000,000

Note: The capital cost figures are only for expressing the development security as a percentage of the total capital cost of each project (see Table 9)
Expected revenue is the contract price times the expected annual generation.

To supplement our review of RFOs, several interviews were performed with various utility credit managers and other stakeholders. Utility interviews were conducted with SCE, PG&E, SDG&E, Xcel Energy, Nevada Power, BPA, and Arizona Public Service (APS).[5] Other interviews were with the California Wind Energy Association (CalWEA); the Electric Power Supply Association (EPSA); the Utility Reform Network (TURN); Davis Wright Tremaine LLP, Milbank, Tweed, Hadley & McCloy LLP; Starwood Energy Group, as well as economists and contract specialists within Black & Veatch.[6]

This report was prepared under the KEMA contract to the California Energy Commission's Renewable Energy office. While an attempt has been made to include information from non-renewable contracting efforts, the document provides greater depth in the renewable energy area.

CHAPTER 4: CREDIT REQUIREMENTS ANALYSIS

Utility credit requirements for the RFOs listed in Table 2 are summarized in this chapter. Two proxy renewable projects, a 40 MW geothermal and a 100 MW wind project, are used to allow for ease of comparison between different RFOs.

The chapter is organized by category of credit, starting with bid deposits, then discussing financial information, development security, and operating collateral. It concludes with a review of the recent changes to 2006 renewable solicitations in California.

Bid Deposits

Bid deposits are not uniform among utilities. Many have no bid deposits at all, or have low fixed-price deposits. LADWP is the only utility to use a per MWh deposit, while California's IOUs use a per kW deposit. Whether the bid deposit is due upon bid submittal or short-list acceptance also varies. Bid deposits for those RFOs in our sample are listed in Table 4 and Table 5.

Table 4. Bid Deposits for Renewable RFOs

Utilty RFO	Bid Deposit	Geothermal Proxy	Wind Proxy
PG&E	$3/kW at short-list	$120,000	$300,000
SCE 2006	$3/kW at short-list	$120,000	$300,000
SCE 2003/2005	$25,000 proposal fee, $3/kW at short-list	$120,000	$300,000
SDG&E, 2005/2006	None specified	$0	$0
Xcel 2004	Proposal fee: $2,000 if > 20 MW, $500 < 2 MW, $1,000 otherwise.	$2,000	$2,000
LADWP 2004	$5/MWh at short-list	$1,489,200	$1,533,000
SCPPA 2005	None specified	$0	$0
SMUD 2004	None specified	$0	$0
Nevada Power 2005	$10,000 for > 10 MW proposal fee	$10,000	$10,000
Pacificorp 2004	None specified	$0	$0

Note: For SCE's 2003/2005 RFO, the $25,000 proposal deposit is applied to the $3/kW bid deposit.

Table 5. Bid Deposits for non-Renewable RFOs			
Utilty RFO	**Bid Deposit**	**Geothermal Proxy**	**Wind Proxy**
SCE 2005 All-Source	None specified	$0	$0
SDG&E 2006 All-Source	None specified	$0	$0
PG&E 2005 All-source	$5/kW proposal fee $10/kW when sent to CPUC	$200,000 $400,000	$500,000 $1,000,000
Xcel 2004 All-Source	Proposal fee: $5,000 if > 20 MW, $1,000 < 2 MW, $3,000 otherwise	$5,000	$5,000
APS 2006 Base-Load	$10,000 proposal fee	$10,000	$10,000

For California IOUs, the CPUC RPS decision conditionally approving 2006 RPS solicitations recommended that utilities use PG&E's $3 per kilowatt as the standard bid deposit for renewable solicitations, due when a project is selected for the utility's short-list.[7] SCE's 2006 proposed renewable RFO uses this amount (with a $25,000 minimum). In earlier renewable RFOs, SCE had used $25,000 proposal fee due on submittal. PG&E's recent all-source RFO uses $5/kW, and SDG&E does not specify a bid deposit for either their renewable or all-source RFOs. SCE's 2005 all-source 5-year RFO does not appear to have a bid deposit. Figure 2 shows the bid deposits for the proxy projects for the California IOUs' 2006 renewable energy RFOs. Bid deposits range greatly, with SCE's and PG&E's deposits higher than most utilities, but lower than at least one (LADWP).

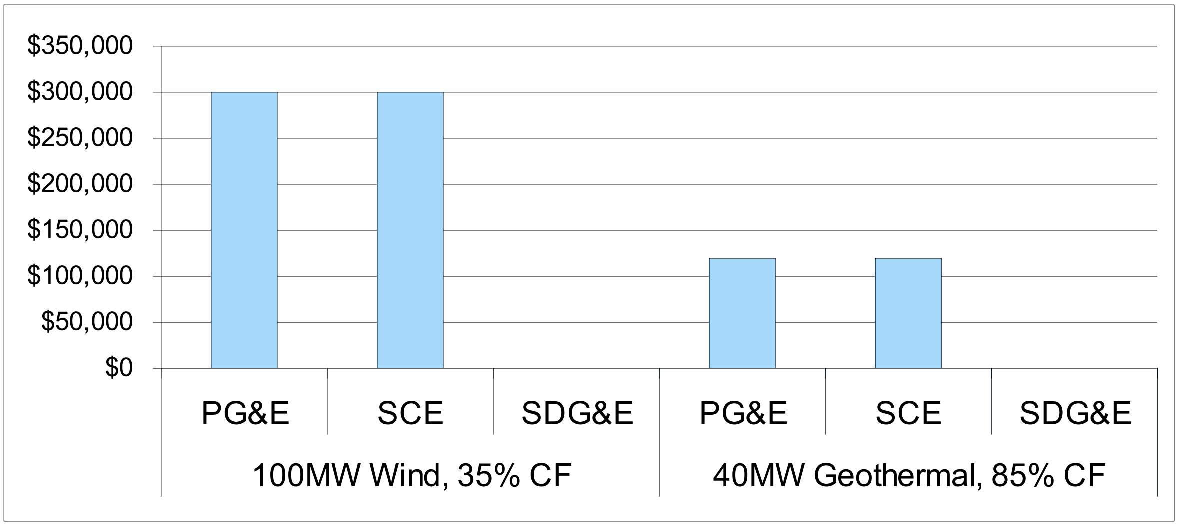

Figure 2. CA IOU 2006 Renewable RFO Bid Deposits for Proxy Projects

Financial Information

All utilities request standard financial information of their bidders, such as 2-3 years of financial statements. Many utilities request detailed pro forma cash-flow models of the projects, along with information about the funding sources of the project, while other RFOs do not request such information. While the utilities may request project budget and financing information, it is unclear whether developers actually provide detailed pro formas as part of their bid packages.[8]

In an attempt to rank the financial information requested, this analysis assigns qualitative ratings to the financial information as described below. Table 6 lists the RFOs, the financial information requested, and the resulting ratings.

- **High** Very detailed information requested, including project pro forma and financing information.
- **Average** Standard financial information requested, possibly project pro forma but no financing plan.
- **Low** Standard financial information, no project information requested.

Table 6. Financial Information Requested		
Utility RFO	**Financial Information Requested**	**Rating**
PG&E Renewables and All-Source	Very detailed information, project financing information and pro forma budget.	High
SCE Renewable (all years)	Standard financial information, pro forma budget.	Average
SCE 2005 All-Source	Standard financial information (uses Edison Electric Institute form).	Average
SDG&E All 2006 RFOs	Standard financial information, no pro forma.	Average
SDG&E 2005 Renewable	2005 RFO includes credit application, which was not available to authors.	N/A
Xcel 2004 Renewable and All-Source	Standard financial information, financing plan, detailed plan for meeting security requirements.	High
LADWP 2004 Renewable	Standard financial information, pro forma budget, financing plan.	High
SCPPA 2005 Renewable	Standard financial information, no budget or financing plan. Project ownership structure requested.	Average
SMUD 2004 Renewable	Financial information for last two years, project assumptions.	Average
Nevada Power Renewable 2005	Project financing plan only.	Low
Pacificorp 2004 Renewable	Project pro forma, financial information, no past financial statement required.	Average
APS 2006 Base-Load	Financial information, past financial statements, project financing sources.	Average

Development Security

Most development security is typically due 30-90 days after contract execution and must be in the form of cash or a letter of credit. A parental guaranty or investment grade credit ratings are rarely allowed to substitute for liquid development security (Pacificorp is an exception to this among our samples). Development security is generally returned after COD, however, a few utilities turn the development security into operational collateral (e.g. Xcel). Table 7 and Table 8 list the development security required by the utilities in our sample.

Table 7. Development Security, Renewables.			
Utility	**Development Security**	**Geothermal Proxy**	**Wind Proxy**
PG&E 2005/2006	$20/kW	$800,000	$2,000,000
SCE 2003/2005/2006	$20/kW	$800,000	$2,000,000
SDG&E 2006	$10/MWh	$2,978,400	$3,066,000
Xcel 2004	$75/kW	$3,000,000	$7,500,000
LADWP 2004	Unspecified	N/A	N/A
SCPPA 2005, SMUD 2004	Unspecified	N/A	N/A
Nevada Power 2005	$4.09/MWh	$1,218,166	$1,253,994
Pacificorp 2004	2 years of expected revenue**	$41,697,600	$36,792,000
**Not required if seller meets collateral threshold. See Table 3 for expected revenue amounts.			

Table 8. Development Security, non-Renewable.			
Utility	**Development Security**	**Geothermal Proxy**	**Wind Proxy**
PG&E 2005 All-source	$61/kW	$2,440,000	$6,100,000
SCE 2005 All-Source	$0	$0	$0
SDG&E 2006 All-Source	Unspecified	N/A	N/A
Xcel 2004 All-Source	$125/kW	$5,000,000	$12,500,000

In California, PG&E and SCE have clearly settled on $20/kW for renewable procurement. For all-source procurement, PG&E requires $61/kW while SCE has no security. This large difference is due to the focus of the two RFOs: SCE's 2005 RFO was for 5-year contracts with a preference for wholesale marketers, while the PG&E's RFO was for new construction. SDG&E has not specified its development security in the past (or it was $0), but in its recent 2006 renewables RFO (submitted to the CPUC on June 9, 2006) it is using $10/MWh, which is significantly higher than SCE or PG&E.

In other jurisdictions, Xcel uses a per-kW method while Nevada Power uses per MWh. Pacificorp's development security is far higher than any other surveyed utility, partly due to it being the only utility that has a collateral threshold for development security. It appears that setting security on an expected generation (MWh) basis may be more equitable for low-capacity factor technologies such as wind and solar, as it is based on the generation of the facility and not the nameplate capacity.

Renewable development security for SCE and PG&E appears lower than most other utilities surveyed, while SDG&E's security is significantly higher. Figure 3 shows the California IOU's 2006 renewable development security for the proxy plants. SDG&E's development security in its 2006 RFO was the first time it has included explicit development security, while SCE and PG&E are consistent with past RFOs.

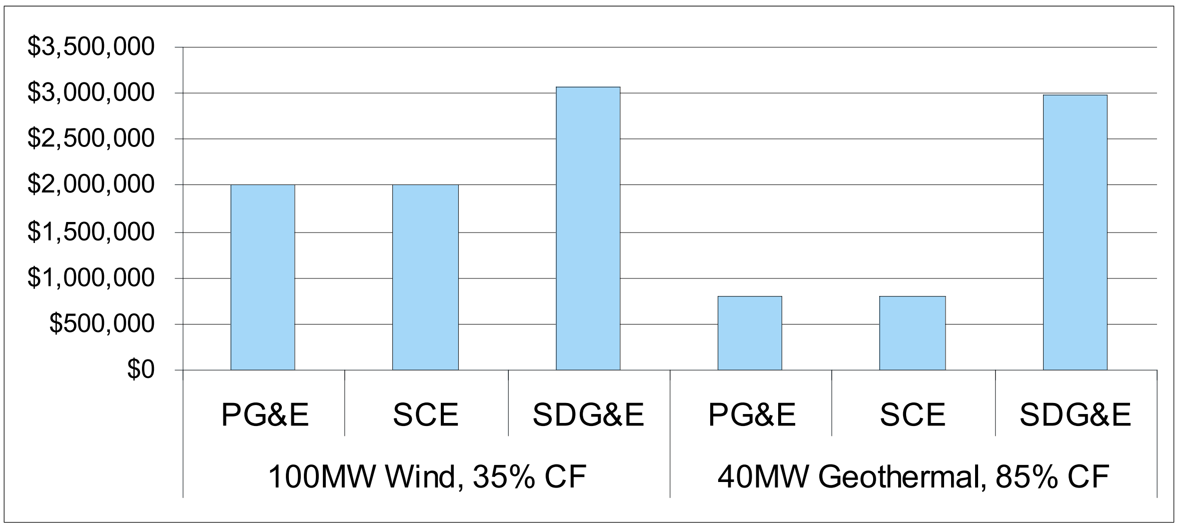

Figure 3. CA IOU 2006 Renewable Development Security for Proxy Projects

Another way to compare development security is to express the security as a percentage of the project's total capital cost as shown in Table 9. While the cost of obtaining a letter of credit is usually 1 to 3 percent of the security required, it is helpful to see the total security as a percentage of capital cost. Obtaining a letter of credit can reduce the borrowing capacity of the project by the amount requested, which can have a significant impact on project financials.

Table 9 shows that development security as a percentage of project cost ranges from 0 to 35 percent. Without including Pacificorp's extremely high security requirements, the average security required is between 1 and 3 percent of total capital costs.

Table 9. Development Security as a Percentage of Capital Cost.			
Utility	**Development Security**	**Geothermal Percent of Capital Cost**	**Wind Percent of Capital Cost**
PG&E 2005/2006 Renewable	$20/kW	0.67%	1.33%
PG&E 2005 All-source	$61/kW	2.03%	4.07%
SCE 2003/2005/2006 Renewable	$20/kW	0.67%	1.33%
SCE 2005 All-Source	$0	0.00%	0.00%
SDG&E 2006 Renewable	$10/MWh	2.48%	2.04%
Xcel 2004 Renewable	$75/kW	2.50%	5.00%
Xcel 2004 All-Source	$125/kW	4.17%	8.33%
Nevada Power Renewable 2005	$4.09/MWh	1.02%	0.84%
Pacificorp 2004	2 years of revenue*	34.75%	24.53%
*Not required if seller meets collateral threshold. RFOs with unspecified security are not shown. Total capital cost is listed in Table 3			

Operating Collateral

Utilities reviewed in this analysis diverge most in their credit requirements when it comes to operating collateral. In addition, collateral thresholds and contract negotiations may result in actual operating collateral requirements that are different than those listed here. For example, a creditworthy developer (or one with a parental guaranty) may only need to post a fraction of the amounts listed in Table 10 and Table 11, as they may have a collateral threshold of several million dollars. Table 10 and Table 11 list operating collateral for the utilities in our sample, assuming a collateral threshold of zero. Figure 4 compares the 2006 California IOU renewable credit requirements.

Table 10. Operating Collateral, Renewables.

Utility	Operating Collateral	Geothermal Proxy	Wind Proxy
PG&E 2006	6, 9, or 12 months revenue (for 10, 15, and 20 year terms)	$20,848,800	$18,396,000
PG&E 2005	6, 9, or 12 months revenue (for 10, 15, and 20 year terms), OR credit assurance (an amount of collateral determined by PG&E), OR replacement cost collateral (mark-to-market)	$20,848,800	$18,396,000
SCE 2006	0, 3, 6 or 12 months revenue, subordinated mortgage	$20,848,800	$18,396,000
SCE 2003/2005	Complex mark-to-market calculation, collateral threshold, subordinated mortgage	Unable to calculate	Unable to calculate
SDG&E 2006	$30/MWh	$8,935,200	$9,198,000
Xcel 2004	Development Security carries over past COD, plus additional subordinated mortgage	$3,000,000	$7,500,000
LADWP 2004	$30/MWh	$8,935,200	$9,198,000
Nevada Power 2005	Development security returned 2 years post COD, no other operating collateral.	$0	$0
Pacificorp 2004	18 months of replacement power/green tags (mark-to-market), collateral threshold.	$10,441,228	$6,149,323

PG&E's 2005 RFO amounts shown are based on 12 months revenue.
SCE's 2006 Renewable RFO asks developers to submit four bid prices, for 0, 3, 6, and 12 months of revenue (12 is shown).
Pacificorp replacement power calculations use Bloomberg's June 1st California spot price ($42.39) as the current market price and $25 as the green tag price.

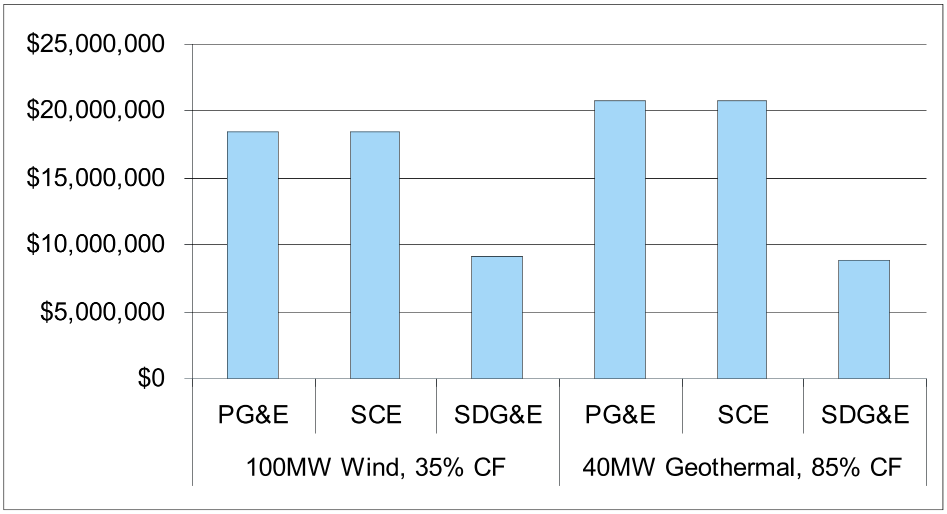

Figure 4. CA IOU 2006 Renewable Operating Collateral for Proxy Projects

Table 11. Operating Collateral, non-Renewable.

Utility	Operating Collateral	Geothermal Proxy	Wind Proxy
PG&E 2005 All-source	Mark-to-market methodology, with either a 2 or 5 year window (depending on time to replace generation), and collateral threshold [1]	$7,446,000	$9,198,000
SCE 2005 All-Source	Mark-to-market [2]	$7,446,000	$22,995,000
SDG&E 2006 All-Source	Unspecified	N/A	N/A
Xcel 2004 All-Source	Development security carries over past COD, plus additional subordinated mortgage	$5,000,000	$12,500,000
APS 2006 Base-Load	Mark-to-market [3]	Unable to calculate	Unable to calculate

[1]Wind is assumed to be a 2-year technology with a possible exposure of $15/MWh. Geothermal is assumed to be 5-year with a possible exposure of $5/MWh (i.e. power prices may go to $75/MWh in five years). PG&E's minimum collateral for the first two years is $30/kW (for 2-year technology) and $60/kW for 5-year technology. PG&E also has a cap of $90/kW for 2-year and $175/kW for 5-year.
[2]SCE's mark-to-market is full collateral over the 5-year term, using a possible future market price of $75/MWh
[3]APS provided no methodology to calculate collateral amounts.

It is difficult to compare operating collateral among utilities. Mark-to-market appears to be standard practice among our limited sample of all-source solicitations (with the exception of Xcel). Of course, how the mark-to-market collateral is calculated varies among utilities, from Pacificorp's 18 months of replacement power to SCE's complex net present value calculations. Non renewable operating collateral requirements are more dynamic than renewable collateral requirements, which are either fixed amounts or may be recalculated annually. Collateral for power marketing contracts is often calculated on a daily basis, as wholesale power rates fluctuate.

For renewable solicitations, there does not seem to be a consensus on operating collateral. Amounts range from a small and limited carryover of development security (Nevada Power) to the amounts required under SCE's and PG&E's solicitations. The current 12 months of revenue that PG&E and SCE use in their 2006 solicitations is roughly twice what other utilities, such as Pacificorp, Xcel, LADWP and SDG&E, require in their renewable contracts.

We were unable to calculate the collateral required by SCE's mark-to-market calculations for their 2003 and 2005 RFOs. Interviews with SCE's credit manager revealed that renewable developers also found it difficult to calculate the amounts required, which was one of the factors leading to the change in collateral requirements for the 2006 RFO.[9] That RFO requires developers to submit four prices, one for no operating collateral, and one for 3, 6 and 12 months of revenue as operating collateral. The results of these bids should provide information on the actual "cost" different levels of operating collateral impose on a project.

One way to compare operating collateral is to determine the portion of the power price that is due to the cost of operating collateral. Table 12 expresses the cost of collateral as a per MWh price. A letter of credit fee of 2 percent of the collateral amount was assumed for these calculations, recognizing that 2 percent is an average fee and developers may be paying more or less for credit. The table shows that, on average, the cost of operating collateral could add about 50 cents per MWh (0.05 cents per kWh) to the price of power, with costs ranging from zero to $1.50 per MWh (0.15 cents per kWh).

Just as with development security, the "cost" to the project may be more than simply the fee for the letter of credit. Obtaining collateral may reduce the borrowing capacity of the project, increasing equity requirements.

Table 12. The Cost of Operating Collateral in $ per MWh.			
Utility	**Operating Collateral**	**Geothermal Proxy**	**Wind Proxy**
PG&E 2006 Renewable	6, 9, or 12 months revenue (for 10, 15, and 20 year terms)	$1.40	$1.20
PG&E 2005 Renewable	6, 9, or 12 months revenue (for 10, 15, and 20 year terms), OR credit assurance, OR replacement cost collateral (mark-to-market)	$1.40	$1.20
PG&E 2005 All-source	mark-to-market methodology	$0.50	$0.60
SCE 2006 Renewable	0, 3, 6 or 12 months revenue, subordinated mortgage	$1.40	$1.20
SCE 2003/2005 Renewable	Complex mark-to-market, collateral threshold, subordinated mortgage	N/A	N/A
SCE 2005 All-Source	Mark-to-market	$0.50	$1.50
SDG&E 2006 Renewable	$30/MWh	$0.60	$0.60
SDG&E 2006 All-Source	Unspecified	N/A	N/A
SDG&E 2005	Unspecified	N/A	N/A
Xcel 2004 Renewable	Development security carries over past COD, plus additional subordinated mortgage	$0.20	$0.49
Xcel 2004 All-Source	Development security carries over past COD, plus additional subordinated mortgage	$0.34	$0.82
LADWP 2004	$30/MWh	$0.60	$0.60
Nevada Power Renewable 2005	Development security returned 2 years post COD, no other operating collateral	$0.00	$0.00

Table 12. The Cost of Operating Collateral in $ per MWh.			
Utility	**Operating Collateral**	**Geothermal Proxy**	**Wind Proxy**
Pacificorp 2004	18 months of replacement power/green tags (mark-to-market), collateral threshold.	$0.12	$0.42
APS 2006 Base-Load	Mark-to-market	N/A	N/A
Average		$0.42	$0.54
Lowest		$0.00	$0.00
Highest		$1.40	$1.50
Data assumes a letter of credit fee of 2 percent of the collateral amount.			

Changes in 2006 Renewable Solicitations

On June 9, 2006, the three California IOUs submitted their renewable RFOs to the California Public Utilities Commission (CPUC) for approval. Credit requirements (particularly bid deposits) had been a topic of discussion in recent rulings, and there are several significant changes in the 2006 RFOs from previous solicitations. The CPUC also recently released an RFP of its own for a consultant to review IOU credit requirements. This section looks at the major changes in credit requirements for the three IOUs in their 2006 RFOs.

PG&E

PG&E's renewable credit policies were originally based in part on a stakeholder workshop.[10] In their 2005 renewable RFO, credit was used as part of the evaluation process. Credit was assigned 20 percent of the overall evaluation score, and bidders were awarded zero, 10 or 20 points based on their proposed security. To receive 20 points, bidders had to put up either a fixed amount of operational collateral (equal to 12 months revenue for 20 year contracts), some type of "credit assurance" acceptable to PG&E, or replacement cost collateral (a mark-to-market calculation). Bidders received 10 points for operational collateral equal to 6 months revenue, and zero points for no security. Table 13 shows the table included in PG&E's 2005 RFO.

Table 13. PG&E 2005 Renewable RFO Credit Scoring			
Score	**10 Year Contract**	**15 Year Contract**	**20 Year Contract**
20 Points	(1) Security Deposit; Development: $20/kW; Post-commercial operation date: 6 months revenue (2) Credit Assurance (3) Replacement Cost Collateral	(1) Security Deposit; Development: $20/kW; Post-commercial operation date: 9 months revenue (2) Credit Assurance (3) Replacement Cost Collateral	(1) Security Deposit; Development: $20/kW; Post-commercial operation date: 12 months revenue (2) Credit Assurance (3) Replacement Cost Collateral
10 Points	(1) Security Deposit; Development: $20/kW; Post-commercial operation date: 3 months revenue	(1) Security Deposit; Development: $20/kW; Post-commercial operation date: 4½ months revenue.	(1) Security Deposit; Development: $20/kW; Post-commercial operation date: 6 months revenue
0 Points	No Security	No Security	

In 2006, PG&E dropped this scoring methodology, as well as the three choices for operating collateral. It now requires a fixed amount of operating collateral equal to 12 months revenue for 20-year contract terms, and does not include credit in its evaluation protocol.

SCE

SCE made several substantial changes to its credit requirements from its 2005 renewable RFO to its recent 2006 RFO. SCE no longer has a $25,000 proposal fee and now has a $3/kW bid deposit, due at short-list, similar to PG&E's (but with a $25,000 minimum). For operating collateral, it asks bidders to submit four different prices: one for no collateral, and three for collateral equal to 3, 6 and 12 months of revenue. Requesting separate prices from developers for different levels of collateral will also allow SCE and regulators to see the effect of collateral requirements on power prices. SCE's 2006 approach is significantly different than the mark-to-market methodology used in previous solicitations, and was informed by feedback from developers in their previous two RFOs and a workshop held in May 2006.[11]

SDG&E

San Diego Gas & Electric RFOs have historically contained little information about what credit bidders were required to provide. In its 2006 renewable RFO, SDG&E specified $10/MWh for development security and $30/MWh for operational security.[12] SDG&E also makes more explicit the financial information it desires from bidders. SDG&E chose to use generation based security, as opposed to SCE and PG&E who use capacity and revenue based amounts. SDG&E continued to include no bid deposit in its RFOs.

CHAPTER 5: SUMMARY AND CONCLUSIONS

This analysis provides information on the credit policies for energy procurement in California and elsewhere in the Western U.S. While it is difficult to draw broad conclusions based on our limited sample, four main points emerge:

- Development security appears to be a small percentage of the capital cost of projects. The project impacts of obtaining development security, however, may be larger than the out of pocket costs as it may affect the borrowing capacity of the project.
- While the collateral amounts may be large, the actual cost of operating collateral on a per MWh basis does not appear to be significant in most cases. Operating collateral averages $0.50/MWh, with the larger amounts in the $1.50/MWh range.
- SCE's pre-2006 mark-to-market collateral requirements proved difficult for renewable developers, but these requirements have been removed in the most recent 2006 RFO.
- Collateral amounts based on nameplate capacity tend to disadvantage wind and other low capacity factor technologies.

It is clear that no consensus exists among utilities regarding credit requirements. There is still healthy debate between regulators, utilities, and developers as to the "appropriate" level and timing of bid deposits, development security, and operating collateral. Several utilities interviewed, such as Nevada Power and BPA, are planning on changing their credit requirements in the near term. California's IOUs have significantly changed their credit requirements due to feedback from regulators and other stakeholders, as discussed in the previous section.

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Endnotes

[1] "Building a 'Margin of Safety' Into Renewable Energy Procurements: A Review of Experience with Contract Failure" CEC-300-2006-004 California Energy Commission Contractor's Report, January 2006.

[2] Correlating failure with mitigation measures was not the focus of the report, and further study is needed to determine this more fully.

[3] Many utility RFOs explicity prohibit developers requiring collateral from the utility.

[4] In states with renewable energy credit (REC) trading, this is not as much of an issue. Pacificorp uses a mark-to-market approach in their operating collateral, using the cost of 18 months of replacement power and RECs.

[5] The author wishes to thank all those that gave generously of their time: David Yi of SCE, Frank DeRosa of PG&E, Karen Hyde at Xcel, Bill Heck of Nevada Power, and Rob Wanless at APS.

[6] Thanks are due to Matt Freedman at TURN, Joe Karp from CalWEA, Steven Greenwald from David Wright Tremaine, Ed Feo of Milbank, Tweed, Hadley & McCloy LLP, Steve Zaminski of Starwood Energy Group, and John Wynne and Larry Loos from Black & Veatch.

[7] California Public Utilities Commission Draft Decision of ALJ Mattson , Opinion Conditionally Approving Procurement Plans for 2006 RPS Solicitations Addressing TOD Benchmarking Methodology, and Closing Proceeding. Proceeding 04-04-026 issued April 25, 2006. www.cpuc.ca.gov

[8] The author's experience in reviewing RFP bids is that few developers provide this information.
[9] Interview with David Yi, SCE.
[10] Interview with Frank DeRosa, PG&E. The date of the workshop is unknown.
[11] See www.sce.com/EnergyProcurement/ for copies of the presentations at the workshop.
[12] SDG&E expresses these as "2 times annual generation times $5/MWh" and "2 times annual generation times $15/MWh" instead of $10/MWh or $30/MWh.